Overview Of The 1991 Arctic National Wildlife Refuge Recoverable Petroleum Resource Update

Bureau of Land Management

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Summary of Findings

The 1991 update of recoverable petroleum resources in the 1987 Arctic National Wildlife Refuge, Alaska, Coastal Plain Assessment, also known as the 1002 Report, makes a considerable contribution to the knowledge and understanding of the petroleum geology of the 1002 area of the Arctic National Wildlife Refuge (ANWR). This study reaffirms most of the conclusions and estimates made in the 1002 Report, and increases the level of confidence that ANWR is part of the North Slope oil province. This is demonstrated by the increase in the marginal probability of economic success from 19 percent in the original assessment to 46 percent in the current assessment. The increase in marginal probability means that ANWR has a higher potential for oil discovery. The overall Minimum Economic Field Size (MEFS) for the 1002 area has been lowered from about 0.44 billion barrels of oil (BBO) to about 0.40 BBO. The mean resource estimate has increased from 3.23 to 3.57 BBO.

Introduction

The original recoverable resource assessment was included in the 1002 Report, published in 1987. It was well received in reviews of the report by industry and the scientific community, but, as was its intent at that time, was considered conservative. The intent of Section 1002(h) of ANILCA was to give the Secretary of the Interior sufficient information to make an informed decision for his recommendation to Congress pertaining to oil and gas leasing in the 1002 area. The 1991 assessment was prepared as a part of routine updating of resource assessments that takes place every 2 to 5 years and that reflects new and reinterpreted geological data, state-of-the-art engineering, current tax provisions, and updated economic data.

Because Congress intended for the 1987 assessment to be conducted with as little impact on the 1002 area as possible, they did not authorize the drilling of test wells. Therefore, the only sources of information available for the 1002 study were records from wells drilled in the surrounding area and about 1,300 line miles of seismic reflection data shot by a consortium of 25 companies on an approximate three-by-six mile grid in the 1002 area. Selected gravity readings collected by industry from the 1002 area and the results of surface geologic work conducted by in-house and various outside sources in and around the coastal plain were also available and beneficial to the study. With this amount of information and given the timeframe for completion of the study, a conservative approach was taken in order not to overestimate the economically recoverable hydrocarbon potential in the area.

Since the 1002 Report was completed in 1987, the BLM in Alaska has obtained access to information from four wells drilled near or adjacent to ANWR. They are Tenneco's Aurora No. 1, Unocal's Hammerhead No. 1, and Shells' Corona No. 1, all located offshore from ANWR, and Unocal's Leffingwell No. 1, located onshore West of ANWR (figure 1). The BLM also obtained approximately 800 line miles of the original seismic data that was reprocessed by industry to enhance the resolution of seismic reflectors of the shallower Brookian sequence rocks and to help increase the understanding of this sequence. Additionally, some offshore seismic lines near ANWR became available. These new data were used in the current analysis. In addition, an in-house study of the petroleum geology of northeastern Alaska through the Mackenzie Delta in western Canada enhanced the understanding of the regional geology. Surface samples of potential reservoir rocks also were analyzed to assess reservoir parameters. Furthermore, the 1991 assessment utilized a LANDSAT analysis of the bedrock geology of the "bulge" of the mountain front south of the 1002 area.

In August 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) issued a draft study of oil and gas development on the North Slope. This was combined with an in-house analysis and a survey of major companies operating on the North Slope to update the engineering and costing of ANWR development. Updated DOE forecasts of oil prices were also included in the analysis.

Geological and Geophysical Analysis

The new and reinterpreted data resulted in an analysis that, although not vastly different from the 1002 report, gave the BLM a greater degree of confidence in their original recoverable resource assessment of 1987, and also increased their knowledge and understanding of the complicated petroleum geology which exists in and around the 1002 area.

The geology studies and seismic information suggested the necessity of updating correlations of the pre-Ellesmerian basement rocks across the area. Elements of these rocks were important to almost all of the previously mapped prospects. The BLM developed a more detailed description of the depositional systems involved in ANWR stratigraphy. This was important in the Brookian sequence rocks as to their location, extent in the subsurface, and relationship to similar rocks in the Canadian Beaufort/Mackenzie Delta area which have successfully tested and produced oil and gas. The new data provided a higher degree of confidence in determining the nature of geological plays described in the original 1002 Report. This is important to the definition of drilling objectives in the mapped prospects.

The geophysical analysis incorporated the new well data, gravity data, and reprocessed seismic data obtained during the 1983-84 and 1984-85 seasons. The reprocessed seismic data provided better resolution to the seismic reflectors defining the shallow (Brookian) part of the section. This allowed the BLM to map several structural closures within this sequence. These prospects were delineated within the area previously mapped as trends (figure III-10 in the 1002 Report). Most of these new prospects are small and either would not be developed or would be developed in conjunction with the prospects mapped in the 1002 Report, over which the new prospects lie. However, in one case, the prospective target is a stratigraphic prospect of some significance. The gravity data correlated well with the seismically mapped structures of the 1002 area, helping to confirm this aspect of the 1987 Report. Geophysical information from the new wells around ANWR was useful for fine-tuning some of the sonic velocities that were used in the original mapping of the 1002 area. The velocity corrections provided more accurate depths to some of the prospects and also supported the reassessment of prospective reservoirs (drilling objectives) in some of the prospects.

PRESTO Model Inputs

The PRESTO (Probabilistic Resource ESTimates, Offshore) model was used to develop resource estimates. One or more prospective targets were defined for each identified prospect based on the potential for reservoir rocks. Reservoir parameters consisted of risks of no hydrocarbons and probability distributions of the physical characteristics of targets within prospects. Three levels of risk were defined: the risk that no recoverable hydrocarbons existed in the area, in each prospect, and in each prospective target in each prospect. Since gas was assumed to be uneconomic, only four parameters were defined for each target: the probability that the resource is oil (rather than gas), and distributions of productive acreage (acres), pay thickness (feet), and oil recovery factor (bbls/acre-foot). Engineering and economic input for PRESTO consisted of specifying minimum economic field sizes. Minimum recoverable resource sizes were set for each of the prospects.

Reservoir Parameters

The 1991 PRESTO inputs of reservoir parameters evolved from updating the ANWR geologic and geophysical database described above. The changes included the addition of a new stratigraphic prospect mapped in the Brookian sequence, and other new prospects associated with the previously identified prospects. Some PRESTO inputs were derived by an iterative process. After each PRESTO run, the sampled means of the geologic parameters were reviewed to ensure that they accurately modeled the database of the regional geologic parameters. Iterative runs were necessary in cases where choices of the PRESTO input parameters were restricted. In these cases, a decision had to be made on which available input choice most accurately modeled the database of regional geological parameters. These updates resulted in revisions of geological risks, play assignments, and the distributions for unit thicknesses, oil recoveries, and productive acres (or trapfill).

Geologic Risk. Geologic risk played a major part in a PRESTO assessment and was the most subjective of the input parameters. In the 1987 resource assessment, ANWR was studied as a separate basin and considered a frontier area. Using other frontier areas as analogs, a rule-of-thumb approach was used in determining individual prospect risks. No prospect was considered to have a risk of less than 90 percent, i.e. no prospect could have a probability of success of greater than 10 percent. This approach assured that the PRESTO-generated probabilities of economic success would be consistent with other frontier onshore areas of the United States. However, reviews of the ANWR assessment by the National Academy of Science and the Department of Energy suggested that this assumption led to conservative resource estimates and unrealistically low probabilities of success.

The current resource update used the regional petroleum geology study, including the additional well data and the interpretation of reprocessed seismic data, to develop an improved understanding of the stratigraphic framework of the 1002 and surrounding area. With this information, it appeared more appropriate to consider the 1002 area as part of the North Slope oil province, rather than as a rank wildcat frontier area, with ANWR the middle section between the Prudhoe Bay area complex and the discoveries in the Mackenzie Delta area (figure 2). In the North Slope province, hydrocarbons were thought to have been generated and trapped by a variety of mechanisms with the probability of an oil or gas show being very high. Therefore, the probability of a new oil or gas discovery under these conditions was considerably greater than reported in 1987. Consequently, the PRESTO inputs and the geologic prospect risk developed in 1991 reflected this situation, resulting in lower prospect risks and area risk. Each prospect in the 1991 assessment update was studied individually, and each had a risk computed for it derived from the USGS/BLM play risks and the BLM seismic risk. This allowed PRESTO to calculate a conditional economic probability for each prospect and eliminated the previous constraint.

As in the 1987 assessment, this analysis assumed a dependence between prospects. Assuming complete independence implies that all of the prospects in the area would be tested in the course of exploration without incorporating the acquired geologic information that became available as the exploration proceeded. Observations of drilling activities on the North Slope and the current knowledge of the geology of ANWR, resulted in an agreement with the 1987 assessment that only 4 to 6 prospects would be tested in the 1002 area to determine its economic viability. Prospects tested later would be dependent on the results of the first tests.

Play Assignments. Plays were extended or reassessed based on well data, seismic data and the regional geology study; potential reservoirs within prospects were then updated.

Unit Thickness. Adjustments were made to several prospects based on offshore well data and a regional geology study.

Oil Recovery. The oil recovery factor calculations were in part based on the gas-oil ratio (GOR). Literature research showed that the GOR used in the original assessment was conservative and not representative of those found on the North Slope. Oil recovery was recalculated using a more accurate figure for GOR.

Productive Acres or Trapfill. Trapfill is the percentage of the maximum areal extent of the trap that contains recoverable oil or gas. Given the maximum acreage for a trap, the trapfill can be converted to a distribution of productive acres. There is very little information available regarding trapfill. In the 1987 1002 assessment of in-place resources, a play analysis was conducted in which trapfill was represented by a seven point distribution. The assessment of recoverable resources, however, required a prospect analysis and utilization of the PRESTO model. Since the seven-point distribution is not available in PRESTO, a triangular distribution for trapfill was substituted for the calculation of recoverable resources in the 1987 report. However, the 1991 update used a lognormal distribution for trapfill. With the current uncertainty regarding trapfill, it was judged that a lognormal distribution better describes field size distributions found in nature.

Minimum Economic Field Size Analysis

Combining the Minimum Economic Field Size (MEFS) with the reservoir parameters in the PRESTO model produces the economically recoverable resource estimates. The inputs into the MEFS analysis can be grouped into four categories: engineering and costs, taxes, macroeconomics, and reservoir characteristics. The result of the MEFS analysis was a slight lowering of the MEFS. Each prospect has its own MEFS, but overall the MEFS decreased from about 440 million barrels to about 400 million barrels. This figure is applicable to western prospects. The eastern prospects, needing a longer pipeline to reach TAPS, required about 550 million barrels as opposed to the 660 million barrels in the 1002 Report.

The MEFS analysis for the 1002 Report was described in the Appendix, Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size, by Young and Hauser (1986). In 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) conducted an extensive literature review, convened public hearings, and collected industry comments for a study of North Slope oil and gas development potential. This included an examination of potential development in the 1002 area. The draft of this study was published in August 1990. The BLM Alaska State Office reviewed this report, compared it with internal information, and followed it with a survey of companies operating on the North Slope to resolve inconsistencies and obtain industry comments on specific data and conclusions presented in the DOE/INEL draft report.

Engineering and Costing. Engineering on the North Slope since the 1002 Report analysis has been more evolutionary than revolutionary. The 1987 1002 analysis had been modeled after the Kuparuk field development. The 1991 analysis incorporated more recent development such as at the Endicott and Milne Point fields which have demonstrated further refinements such as smaller pad sizes that slightly lowered costs and decreased environmental impacts. Endicott is an offshore field developed on gravel islands where space is limited; Milne Point is a small field north of the Kuparuk field.

The major engineering and costing assumption incorporated into this analysis is the stand-alone assumption. This means that development of any prospect must cover all the costs of facilities and transportation requirements by itself. In other words, there is no cost sharing consideration for multiple field development, either simultaneous or sequential. This assumption was used in the 1002 Report. The DOE/INEL study reported tests of some hypothetical examples of multiple small discoveries and noted the resultant impact on minimum economic field sizes. This required them to make assumptions as to which prospects and under what conditions the prospects could share costs, which generally are unreliable and tend to be very subjective. The 1991 update focused on fields with sufficient significance to justify initial development in the 1002 area. Although smaller fields would be economic as a result of this development and would likely be developed later, they are not included in the resource assessment. The engineering and costing focused on minimum economic field sizes since PRESTO only requires the use of this threshold field size.

Exploration assumptions did not change from the 1002 Report: one exploration well drilled into the crest of the prospect the year after leasing, followed by two delineation wells each of the next

3 years into the deepest parts of the prospect. Since there was little recent data available on North Slope exploration, particularly in remote areas, the DOE/INEL study estimated these costs based on the 1002 Report exploration costs. However, BLM's later survey of industry indicated that this estimate was too low. This resource assessment used a cost function based on the industry survey and was consistent with the cost of drilling the KIC well on Native lands within the 1002 area. The BLM will continue to gather engineering and cost information related to new technology, and will consider them in any future updates.

The DOE/INEL study contained an extensive review of production facilities and their costs. The facilities are similar to those used in the 1002 Report, and take into account improvements in the footprint and efficiency. The DOE concentrated on the cost savings from facility sharing. While this is of interest with regard to later development of smaller adjacent fields, the present resource assessment is primarily concerned with initial development. The DOE/INEL estimated a cost surcharge of 15 percent for the first development in a remote area. The BLM's industry survey concurred with DOE's estimates for facilities costs.

The engineering of development drilling has changed little from the 1002 Report. In both the DOE/INEL study and this resource assessment, the number of wells required is still calculated as before. The DOE/INEL hypothesized different categories of development based on field size. For fields relevant to the MEFS analysis, DOE used the same development schedule as the 1002 Report, i.e., 6 years of development drilling with production starting in the 5th year of development and production peaking the year after completing the development. The BLM's industry survey strongly indicated that this was too long as it should be only 5 years of drilling with production starting in the 5th year and peaking the following year. The costs of development provided more disagreement. The DOE estimated a cost function for development drilling based on actual costs in existing fields, demonstrating how costs have declined dramatically over the past decade. However, DOE felt that these costs would not apply to a remote area such as the 1002 area and revised the 1002 Report cost functions, essentially eliminating the cost reductions gained in the past decade. The DOE then applied a learning curve to reduce costs by one-half over 5 years. Industry strongly disagreed with these estimates, indicating that the latest advances used at Endicott and Milne Point fields would also apply to 1002 developments. Costs would initially be somewhat higher than in existing fields, but would quickly drop as infrastructure was built up and the operators became familiar with ANWR. Thus, at depths to fifteen thousand feet, the estimated costs were much less than the DOE costs, in some cases were as low as one-half the DOE cost. At deeper depths costs increased rapidly, approaching DOE's costs at around twenty thousand feet.

Based on the DOE/INEL study and the concurrence of industry, the estimated production schedule was similar to that in the 1002 Report except that these small fields would have a 15 rather than a 12 percent annual decline. This assessment used two refinements in engineering that were introduced in DOE/INEL's North Slope study: using the increasing water cut and the decline in the number of active producing wells. Water cut is the percentage of fluid production that is water. As a field is depleted, the water cut increases. At the start of production, it is assumed that 40 percent of wells drilled are used for injection. As the reservoir gets depleted, some production wells are converted to injection wells. The water cut is used in calculating operating costs, while the number of active producers is used in the severance tax calculation. Analyzing the existing fields on the North Slope, DOE obtained a more accurate representation of production costs based on total fluid production rather than oil production. Industry concurred with these costs and they were used in this resource assessment.

The DOE/INEL reviewed the three components of transportation costs; a pipeline from ANWR to TAPS, a tariff for using TAPS to Valdez, and tankering from Valdez to the lower 48. The TAPS tariff is comparable to the numbers in the 1002 analysis. This assessment used the same spreadsheet used by the State of Alaska to estimate future tariffs, including the costs of corrosion abatement and increased oil spill response capability. The DOE found that the average tanker cost was less than that used in the 1002 Report due to a higher proportion going to the West Coast rather than the Gulf Coast. The DOE did not have data to update the costs for the pipeline from the 1002 area to TAPS and thus used the function from the 1002 Report. However, industry strongly disagreed with this estimate. Based on their own internal studies of a pipeline from the 1002 area to TAPS, industry provided the lower cost estimates used in this resource estimate.

The stand-alone assumption and the facilities and ANWR pipeline costs are the primary factors for determining the MEFS. The development drilling costs also become a major factor for every deep, low yield prospect.

Taxes. Several changes have occurred in taxes since the 1002 analysis. The Federal tax code has changed but generally had little effect. Assuming development by a major oil company, the modification of the tax deductions is offset by the reduction in the corporate tax rate. The minimum tax provisions were assumed to have no impact. The State altered its severance tax by raising the tax for very large fields. Since this analysis is looking for the minimum economic field size, this change had only a marginal impact.

Macroeconomics. The macroeconomic assumptions covered four areas: discount rate, oil prices, the role of natural gas, and inflation. The discount rate used in this assessment was the same used by Young and Hauser for the 1002 Report, i.e., a real after-tax rate of 10 percent. The oil price scenario used was the DOE National Energy Strategy Reference Case. This resulted in a lower price schedule than that used in the 1002 Report, but was closer when taking into account the delay in opening the 1002 area of ANWR. Natural gas was still assumed to be uneconomic for purposes of estimating the MEFS due to the uncertainty of available transportation and the huge reserves already available on the North Slope. Although the gas eventually may be developed, the decision to develop the 1002 area in the next 10 years will not depend on the development of natural gas resources. Inflation is assumed to average four percent a year rather than the six percent used in the 1002 Report. This figure is comparable to inflation rates used in the DOE report and long range analyses by firms as DRI/McGraw-Hill. Since inflation was incorporated in cost and price escalation as well as the nominal discount rate, the impact on the MEFS was marginal. The decline in the price estimates was offset by the decline in the costs, resulting in the lower MEFS.

Reservoir Characteristics. The reservoir parameters previously described were used in estimating the MEFS. For each prospect, a risk-weighted average oil recovery factor was calculated, conditioned on the existence of hydrocarbons in the prospect. In testing a resource size for the MEFS, the average recovery was used to calculate the number of acres required to contain oil. If the acres required exceeded the areal extent of the prospect, then the maximum productive acreage was used, increasing the recovery factor to that necessary to yield the tested resource size. The acreage in turn determined the number of wells needed to develop the prospect.

PRESTO III Analysis Results

The results of this new study show that at the mean, there are 3.57 billion barrels of conditionally economically recoverable oil resources for the 1002 area with a marginal probability of economic success of 46 percent. The large increase in the marginal probability was due to:

1. Adding a reservoir to some of the prospects which made their economic probability greater;

2. Increasing the number of mapped prospects;

3. No longer considering the 1002 area as a frontier area for oil exploration and not constraining the individual prospect probability of success; and

4. Having a slightly smaller economic field size.

Conclusion

Mineral assessment is a dynamic process. As new information becomes available, it will be necessary to review previous assumptions and models and, if necessary, make adjustments to previous assessments. The BLM has gained considerable experience and improved its expertise in analyzing the complicated foreland fold and thrustbelt type geology which exists in ANWR. The 1991 ANWR assessment update has reaffirmed the previous resource estimates and increased the confidence that these resources will be found. This confidence level is reflected in the increase in the marginal probability from 19 percent to 46 percent.

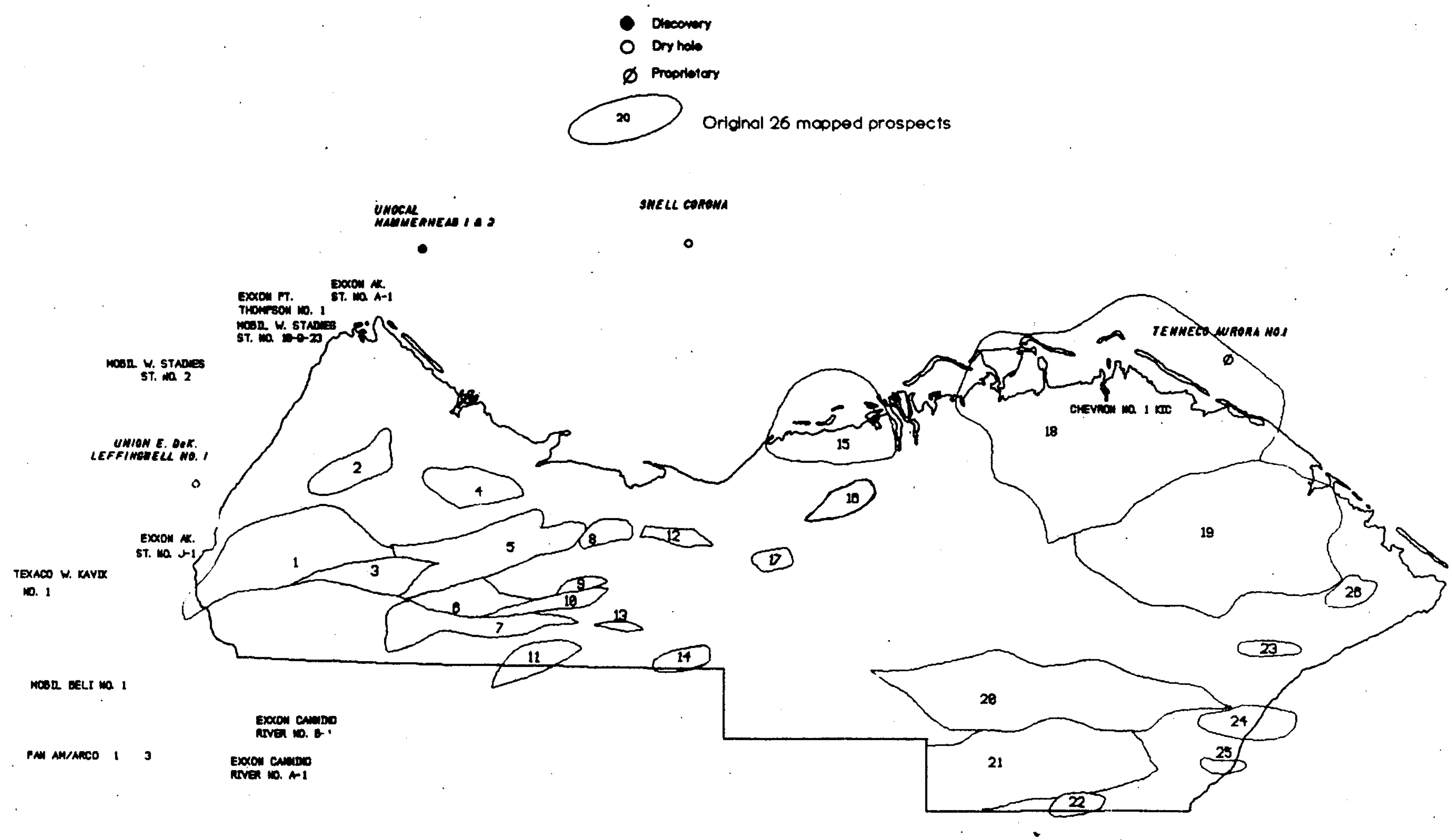

Fig. 1 Pertinent wells studied for 1990 ANWR Update

(Well locations approximate, KIC well not studied)

(Extracted from Banet, Foland, Lalla. 1990)

MAJOR OIL / GAS DISCOVERIES

North Slope, Alaska and Mackenzie Delta, C∃nada

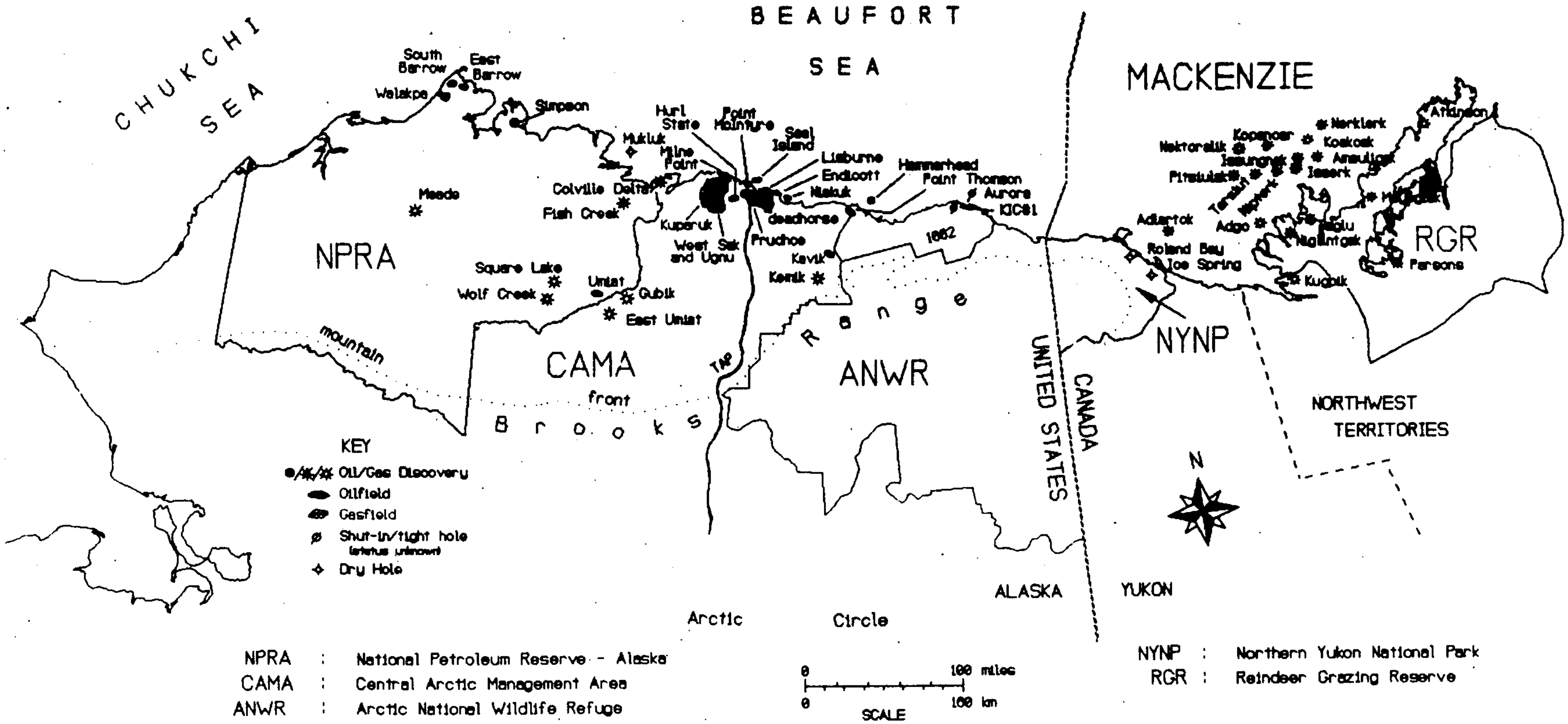

Fig. 2 Northern Alaska/Canada Oil & Gas discoveries

(From Banet,1990, in press)